SECTION 2 – PLUME MODEL

This discussion of the Plume Model used for Hackberry Carbon Sequestration Well No. 001 was prepared to meet the requirements of SWO 29-N-6, **§615.31** [40 CFR **§146.84**]. This section describes the key details of the plume model. The plume defines the pore space rights, area of review (AOR) for the well, corrective action plan if necessary, and overall viability of the project. The Hackberry Carbon Sequestration project will be comprised of three (3) wells for a total project injection capacity of 4.5 million metric tons of carbon dioxide being injected and sequestered per year.

[redacted]

This modeling software used to evaluate this project was Computer Modelling Group's GEM 2020.11 (GEM) simulator. Computer Modelling Group (CMG) has put together one of the most accurate and technically sound reservoir simulation software packages for conventional, unconventional, and secondary recovery. GEM utilizes equation-of-state (EOS) algorithms along with some of the most advanced computational methods to evaluate compositional, chemical, and geochemical processes and characteristics to produce highly accurate and reliable simulation models for carbon sequestration.

[redacted] GEM utilizes the compositional methods described above along with equations specific to CO_2 to effectively model and simulate plume behavior within the injection intervals.

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Model Inputs

Trapping Mechanisms

The flow of CO_2, or plume migration, can be defined by five primary trapping functions: structural, hydrodynamic, residual gas (hysteresis), solubility, and geochemical. Each of these functions is explained in further detail below.

Structural Trapping

Structural trapping is a physical form of trapping caused by geological structures. CO_2 is much lighter than the connate brine and therefore tends to float to the top of the injected formation and is stored beneath the cap rock. For this model, CO_2 mass density ranges from between 38 lb/ft^3 in the shallow injection intervals and up to 53 lb/ft^3 in the deep injection intervals, whereas brine density is approximately 68 lb/ft^3. Common examples of structural trapping include cap rock geology such as shales which prevent upward migration of the injected gases and faults or pinchouts which can limit the lateral extent of the plume migration within the reservoir.

Hydrodynamic Trapping

Hydrodynamic trapping is another physical form of trapping caused by the physical interaction of CO_2 and brine. The carbon dioxide will push against and/or mix with the brine differently depending on pressure deltas and phase of the CO_2. This mechanism is particularly effective in laterally unconfined sedimentary basins with limited structural traps, but with large-scale flow systems and low groundwater and fluid flow rates as is seen in the Hackberry location.

For both structural and hydrodynamic trapping, equation-of-state (EOS) calculations are performed to determine the phase of CO_2 at any given location based on pressure and temperature. Several well-known EOS formulae are used within the oil and gas industry for reservoir modeling. These include the Van der Waals equation, the Peng-Robinson method, and the Soave-Redlich-Kwong method. The EOS implemented within the Hackberry Carbon Sequestration Well No. 001 model was the Peng-Robinson (1978) due to its widely accepted use for volumetric and phase equilibria.

Residual Gas Trapping

Residual gas trapping is the physical trapping of CO_2 within pore space. As water is displaced in the rock, the CO_2 fills in the space. However, depending on the movement of CO_2 and the aqueous phase through saturation and capillary forces, CO_2 will remain imbibed within the pore space and become trapped. As with the structural and hydrodynamic trapping discussed above, several methods are used in the petroleum industry for determining residual gas trapping such as the Carlson and Land model and the Larsen and Skauge model, both of which are available in GEM. For the purposes of the simulation discussed herein, the Larsen and Skauge model was used for its ability to determine 3-phase relative permeabilities which includes water phase hysteresis. Whereas the Carlson and Land model is somewhat limited in that it is primarily used for 2-phase hysteresis between oil and gas only.

Solubility Trapping

Solubility trapping is a form of chemical trapping between CO_2 and brine. CO_2 is highly soluble in brine with the resulting solution having a higher density than the connate brine. This feature affects the reservoir by causing the higher density brine to sink within the formation thereby trapping the CO_2-entrained brine. This dissolution allows for an increased storage capacity and decreased fluid migration.

For solubility modeling, GEM offers the options of the Harvey (1996) and Li-Ngheim's (1986) methods. While the Harvey method is often preferred in situations with extremely high sodium chloride content, the Li-Ngheim's method was chosen due to its ability to include solubility parameters specific to CO_2, which were defined using Henry's Law Constant Correlations.

Geochemical Trapping

Geochemical trapping, or mineral trapping, is another form of chemical trapping that occurs due to reactions between CO_2 and the geochemistry of the disposal formation. During injection of CO_2 into the disposal reservoir, four (4) primary chemical compounds are found: CO_2 in supercritical phase, insitu hydrochemistry of the connate brine, aqueous CO_2, and the geochemistry of the formation rock. The aqueous CO_2 is an ionic bond between the CO_2 gas and connate brine within the formation. These compounds will all interact with each other often resulting in CO_2 being precipitated out as a new mineral. This new mineral is typically Ca CO_3, or calcium carbonate (limestone).

Mineral trapping can also occur due to the adsorption of CO_2 onto clay minerals. Once hysteresis and solubility trapping have been included in the model, geochemical formulae can be added through an internal geochemistry database to describe mineral trapping reactions. For aqueous reactions, the following formulae were used:

$$CO_2(aq) + H_2O = H^+ + HCO_3^-$$
$$CO_3^{-2} + H^+ = HCO_3^-$$
$$OH^- + H^+ = H_2O$$

These three (3) reactions are all common ionic reactions that can occur in the reservoir between water and/or CO_2. The following formulae show the mineral reactions used within the model. Each of these is a common mineral found within sandstone in an underground aquifer and cause the precipitation of carbon oxides in a solid state:

$$Anorthite\ (CaAl_2Si_2O_8) + 8H^+ = 4\ H_2O + Ca^{2+} + 2Al^{4+}$$
$$Calcite\ (CaCO_3) + H^+ = Ca^{2+} + HCO3^-$$
$$Kaolinite\ \left(Al_2Si_2O_5(OH_4)\right) + 6H^+ = 5H_2O + 2Al^{3+} + 2SiO$$

While geochemical trapping can have a greater impact on carbon dioxide over hundreds or thousands of years, the short term effects of these trapping mechanisms are relatively small, and fluid movement is predominated by hydrodynamic and solubility trapping. Due to both the current limitations in data for the compositions of these minerals and components in the reservoir and the computational stress added to the software, the geochemical trapping mechanisms have not been assumed in the current model. As more data is received on the geochemical properties of the reservoir, sensitivities could be run to determine the applicability of these traps.

Stratigraphy of Location

[redacted]

Hydrogeology

[redacted]

[redacted]

[redacted]

[redacted]

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Relative Permeability and Capillary Pressure

[redacted]

[redacted]

A study was presented at the SPE Annual Technical Conference and Exhibition in October 2003 that focused on correlations used to determine maximum residual gas saturation in various sandstone reservoirs. From this study, it was found that for sandstone with large porosity, and specifically sandstone with large pore sizes, had the ability to trap more residual gas (Suzanne et al., 2003). [redacted]

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Initial Conditions

The model is assumed to initially be completely brine filled. [redacted]

[redacted]

[redacted]

Injection Rate

The injection rate can be limited by either a set maximum injection rate or maximum pressure in the wellbore. [redacted] The calculations for fracture pressure are shown in Eaton's Equation below, where FG is the fracture gradient, ν is Poisson's Ratio, OBG is overburden gradient, and P_p is the pore pressure gradient:

$$FG = \frac{\nu}{1-\nu}\left(OBG - P_p\right) + P_p$$

[redacted]

Injected Composition

The composition of the injected fluid in the model is based on the actual expected components to be injected. [redacted]

[redacted]

[redacted]

Completion Plan

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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[redacted]

Model Orientation and Gridding Parameters

Spatial Conditions

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Boundary Conditions

[redacted]

Model Timeframe

[redacted]

Model Results

After variable inputs for all of the above parameters, the model was run. The primary objective of the model is to optimize injection patterns to reduce the horizontal extent of the plume while keeping below the fracture pressure for the targeted injection rate. [redacted]

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